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Planning Assumptions Update and Scenarios for use in the CPUC Rulemaking R.13-12-010 (The 2014 Long-Term Procurement Plan Proceeding), and the CAISO 2015-16 Transmission Planning Process

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1 Introduction

This document includes minor updates that were made to the standard planning assumptions adopted for use in the 2014 Long-Term Procurement Plan (LTPP) proceeding (R.13-12-010). The standard planning assumptions were issued by Assigned Commissioner's Ruling on February 27, 2014 and revised by two subsequent technical updates adopted on May 14, 2014, and March 4, 2015. This document is intended to continue to provide a basis for resource planning studies being conducted in the 2014 LTPP, and to provide specific updates applicable to the 2015-16 California Independent System Operator (CAISO) Transmission Planning Process (TPP).[1] This minor update makes a limited number of changes to reflect new information and does not attempt to develop new scenarios. The changes consist of: revised technical attribute assumptions regarding solar PV projects (sections 4.1.5 and 4.2.8); a revised "Trajectory" renewables portfolio to be used in the 2015-16 CAISO TPP (section 4.2.7); use of the Transmission Expansion Policy Planning Committee (TEPPC) 2024 Common Case version 1.5 (section 4.2.13); and revised resource addition and retirement assumptions (sections 4.2.14, 4.2.10, and 4.2.12). The stakeholder process necessary to develop a full update of assumptions and scenarios for use in the 2016 LTPP proceeding and the 2016-17 TPP will occur later in 2015. California Public Utilities Commission (CPUC) Energy Division staff prepared this document in collaboration with staff of the California Energy Commission (CEC) and the CAISO.

1.1 Terminology

Acronym	**Definition**
CPUC	California Public Utilities Commission
CEC	California Energy Commission
CAISO	California Independent System Operator
ARB	Air Resources Board
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
IOU	Investor Owned Utility

[1] In the 2015-16 TPP, the CAISO will conduct local capacity requirement analyses for the LA Basin and San Diego local areas, and the Moorpark subarea of the Big Creek/Ventura local area. Full analyses of all local areas occur every two years, on cycles starting on even years.

POU	Publicly Owned Utility
LSE	Load Serving Entity
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric

1-in-10	1-in-10 year weather peak demand forecast
1-in-5	1-in-5 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
CED	California Energy Demand Forecast (CEC)
DR	Demand Response
DSM	Demand Side Management
CHP	Combined Heat and Power
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report (CEC)
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LTPP	Long Term Procurement Plan (CPUC)
MW	Megawatt
NQC	Net Qualifying Capacity
OTC	Once Through Cooled
PTO	Participating Transmission Owner
PV	Photovoltaics
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SB	Senate Bill

SGIP	Self-Generation Incentive Program
TPP	Transmission Planning Process (CAISO)

1.2 Definitions

- **Assumption**: a statement about the future for a given load or resource. For example, future load conditions are an assumption.
- **Scenario**: a complete set of assumptions defining a possible future world. Scenarios are driven by major factor(s) with impacts across many aspects of loads and resources. For example, a change in the energy load forecast would be considered a new scenario since the change would impact other variables including the amount of renewables and transmission needs.
- **Portfolio**: a component of scenarios, portfolios are the mix of resources to be modeled, created as a result of applying the assumptions in a specific scenario. A high distributed generation scenario, for instance, would have a different portfolio of resources than a 33% base case scenario. RPS portfolios refer specifically to the portfolio of supply-side renewable resources in a given scenario.
- **Sensitivity**: a variation on a scenario where only one variable is modified to assess its impact on the overall scenario results. Removing Diablo Canyon Power Plant, while holding other assumptions constant, is an example of a sensitivity. Changing the energy load forecast would be considered a new scenario rather than a sensitivity since the change would impact other variables including the amount of renewables and transmission needs.
- **Load Forecast**: refers to electricity demand, measured by both annual peak demand and annual energy consumption. Load forecasts are influenced by economic and demographic factors as well as retail rates.
- **Managed Forecast**: refers to a load forecast that has been adjusted to account for the impact of programs or expectations not embedded into the original forecast. An example is adjusting the California Energy Demand Forecast to account for energy efficiency programs not yet funded but with expectations for funding and specific programs in the future.
- **Probabilistic Load Level**: refers to the specific weather patterns assumed in the study year. For example a 1-in-10 Load Level indicates a high load event due to weather patterns expected to occur approximately once every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.
- **Resource Plans**: refer to the need to build new resources or maintain existing resources from an electrical reliability perspective.

- **Bundled Plans**: refer to the three large Investor Owned Utilities' procurement plans established in compliance with AB 57 to determine upfront and reasonable procurement standards.

1.3 Background

The Long-Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[2] A major component of the LTPP proceeding addresses the overall long-term need for new system reliability resources, including the adoption of system resource plans.[3] These resource plans will allow the CPUC to comprehensively assess the impacts of state energy policies on the need for new resources. Based on these system resource plans, the CPUC shall consider updates to the Investor-Owned Utilities' (IOUs) bundled procurement plans with a focus on the IOUs' obligation to maintain electric supply procurement responsibilities on behalf of IOU customers.

The 2014 LTPP proceeding is examining system and local reliability issues based on the adopted set of planning assumptions and scenarios. The CPUC initiated the 2014 LTPP proceeding (R.13-12-010) by a Rulemaking issued on December 19, 2013. On December 11, 2013, draft planning assumptions and scenarios were sent to parties. On December 18, 2013, CPUC Energy Division held a public workshop, and in January 2014, received comments from LTPP parties regarding the proposed set of planning assumptions and scenarios to be studied in the 2014 LTPP proceeding. The planning assumptions and scenarios were adopted by Assigned Commissioner's Ruling on February 27, 2014 with a technical update adopted on May 14, 2014.

Because the CAISO's annual Transmission Planning Process (TPP) and the CPUC's LTPP utilize similar planning assumptions, ~~in its annual Transmission Planning Process (TPP),~~ these ~~planning~~ assumptions should ~~be alignment and consistency with the planning assumptions used~~ align and be consistent. ~~in CPUC planning processes.~~ In order to ensure this alignment and consistency between the LTPP and TPP planning assumptions, the CPUC ~~intends to update~~updates the planning assumptions on an annual basis in coordination and collaboration with the CAISO and the CEC. The annual update occurring in the middle of the 2014 LTPP proceeding was adopted by Assigned Commissioner's Ruling on March 4, 2015 specifically to be available for use in the 2015-16 CAISO TPP.

[2] Pursuant to AB 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling resources to resume procurement of resources. *See also* OIR 3/27/2012, Scoping Memo 1.

[3] *See* Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, Rulemaking (R.)12-03-014, issued May 17, 2012.

1.4 History of LTPP Planning Assumptions

Since the 2006 LTPP, the CPUC has worked to improve transparency and data access, and to streamline long-term procurement planning processes. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards*.[4] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division held several workshops in the summer of 2010, and in December 2010 the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[5] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.[6] This document refines earlier efforts and furthermore seeks to achieve transparent and consistent assumptions and coordination for resource planning activities across the energy agencies.

2 Guiding Principles

The Guiding Principles[7] for developing assumptions to be used and scenarios to be investigated in the 2014 LTPP Rulemaking:

A. **Assumptions** should take a realistic view of expected achievements from established policies while exploring potential impacts from possible policy changes.

B. **Assumptions** should reflect real-world possibilities, including the stated positions or intentions of market participants.

C. **Scenarios** should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably submitted with publicly available engineering or market-based price data checked against confidential market price data for accuracy.

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[4] *Energy Division Straw Proposal on LTPP Planning Standards*, http://docs.cpuc.ca.gov/published/Graphics/103215.PDF

[5] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[6] Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, D.12-12-010, issued December 20, 2012.

[7] *See* Assigned Commissioner's Ruling on Standardized Planning Assumptions, R.12-03-014, issued June 27, 2012.

D. **Scenarios** should inform the transmission planning process and the analysis of flexible resource requirements to reliably integrate and deliver new resources to loads.[8]

E. **Scenarios** should be designed to form useful policy information, for example tracking greenhouse gas reduction goals, and reliability implications of existing and expected resource procurement policies.

F. **Resource portfolios** should be substantially unique from each other.

G. **Scenarios** should inform bundled procurement plan limits and positions.

H. **Scenarios** should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

I. Resource planners including the CPUC, CEC, and CAISO should strive to reach agreement on planning assumptions, and commit **to transparent, consistent, and coordinated planning processes.**

3 Planning Scope: Area & Time Frame

The following assumptions and scenarios are created specifically with regard to the loads served by and the supply resources interconnected to the CAISO-controlled transmission grid and the associated distribution systems. The LTPP planning period is established as twenty years in order to consider the major impacts of infrastructure decisions now under consideration. While detailed planning assumptions are used to create an annual loads and resources assessment in the first period (2014-2024), more generic long-term assumptions are used in the second period (2025-2034), reflecting heightened uncertainties around future conditions[9]. The second period is designed to inform resource choices made today as well as shape policy discussions, and not to make authorizations of need in those years. The CPUC primarily expects technical studies of system and local reliability in 2024 to inform procurement decisions. However, the CPUC does not limit itself to studying 2024 and may also consider technical studies of interim years before 2024. The CAISO's TPP studies target several years within the first ten-year period, including the tenth year for long-term local reliability studies. In the 2014-15 TPP, long-term reliability studies focused on 2024, while the 2015-16 studies will

[8] Scenarios used by the CAISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the CAISO's tariff. Scenarios developed in the LTPP process may inform the development of the CAISO's TPP scenarios to the extent feasible under the CAISO tariff and adopted by that organization.

[9] The updates incorporated in this document will also inform the 2015-16 TPP studies for the 2015-2025 timeframe.

focus on 2025.[10] As such, the staff of the CPUC, CEC, and CAISO focused on developing the most reasonable set of assumptions up to year 2024 for the LTPP and up to 2025 for the TPP. This document supersedes the previous versions of assumptions and scenarios in this proceeding.

4 Planning Assumptions

A description of assumptions is provided in this section. All values are reported in the 2014 Scenario Tool, a spreadsheet developed by CPUC staff to quantitatively present the load and resource assumptions for each of the scenarios described in this document.~~[11]~~ The most recent version is 2014 Scenario Tool version 5.[12]

4.1 Demand-side Assumptions

4.1.1 Base, Incremental, and Managed Forecasts

Demand-side assumptions are either base forecasts or incremental to the demand forecast. Base values, such as the California Energy Demand Forecasts (CED),[13] are independent forecasts without ties to any other forecast. Incremental resource projections, such as Additional Achievable Energy Efficiency[14] (AAEE, formerly known as Incremental Uncommitted Energy Efficiency, or IUEE), are not embedded in the base forecast, but can be used to modify the base forecast to create a net or "managed" forecast. As an example, in the CED, which is treated as

[10] As stated in an earlier footnote, in the 2015-16 TPP, the CAISO will conduct local capacity requirement analyses for the LA Basin and San Diego local areas, and the Moorpark subarea of the Big Creek/Ventura local area. Full analyses of all local areas occur every two years, on cycles starting on even years.

~~[11] The most recent version of the 2014 Scenario Tool, and previous versions are posted to the following location: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm~~

[12] The most recent version of the 2014 Scenario Tool, and previous versions are posted to the following location: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

[13] The CED: California Energy Demand 2014-2024 Forecast, http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/

[14] The AAEE projections: Estimates of Additional Achievable Energy Savings, Supplement to California Energy Demand 2014-2024 Forecast, http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/Additional_Achievable_Energy_Efficiency/

a base load forecast, the CEC embeds an amount of energy efficiency representing current codes and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded, so AAEE is considered an incremental resource projection. Reducing the base load forecast by the AAEE incremental impacts creates a managed load forecast. Assumptions originating from other state agencies, for example the CED, will not be re-litigated in this proceeding.

4.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits of these resources. Reliability studies in transmission-constrained local areas depend on these demand-side resources providing capacity value at least within the electrical areas forecasted, and preferably at specific transmission-level busbar or substation locations if they are to offset local capacity requirements. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. However, the current California Energy Demand set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is moving in the direction of greater locational certainty by providing impacts at the climate zone level. The CEC defines 15 climate zones in California.[15] Efforts are underway to further refine the locational certainty of all demand-side resources so that their benefit as substitutes for conventional generation can be realized in future planning cycles.

4.1.3 Load

The CEC's 2013 Integrated Energy Policy Report (IEPR) California Energy Demand (CED) forecasts serve as the source for the "managed demand forecast," consisting of a base load forecast coupled with several alternative Additional Achievable Energy Efficiency (AAEE) projections (see subsection on Energy Efficiency below). The CED base forecasts include three load cases, "Low", "Mid", and "High", each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants, for example, 1-in-2 weather year and 1-in-10 weather year. The 2014 LTPP Scenarios incorporate the "Mid" and "High" load cases.

[15] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

The 2013 IEPR CED forecasts account for transportation electrification given existing state policies. Development of policies that drive higher electrification growth is underway, and may include increased penetration of electric vehicles (EVs) across all vehicle types, and accelerated rail electrification. As the impacts of such policies become more certain, future planning assumptions will consider accounting for such policies by adjusting the base load forecast (e.g., changes in load shapes and higher annual energy consumption).

The CEC adopted the CED base forecasts on December 11, 2013, and published final versions in spreadsheet format.[16] The 2013 IEPR final report, published on January 23, 2013,[17] based on the IEPR record and in consultation with the CPUC and the CAISO, recommends that the Mid load case (and associated peak demand weather variants) of the CED base forecasts shall be used for long-term infrastructure planning activities at the CPUC, CEC, and CAISO.

The CEC staff made its 2014 IEPR Update CED forecasts available in December 2014, and the CEC adopted a slightly revised version in January 2015. Therefore, the 2015-16 CAISO TPP is expected to use the 2014 IEPR Update CED forecasts (Mid load case) as its source for the "base demand forecast".[18] Adjustments to this base forecast, such as subtracting AAEE, produce a "managed demand forecast" that incorporates demand-side policy goals not included within the CEC's base demand forecast.

4.1.4 Energy Efficiency

Energy efficiency forecasts shall be developed from the CEC's 2013 IEPR CED base forecasts and its supplemental Additional Achievable Energy Efficiency (AAEE) projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AAEE projections from the CPUC's 2013 California Energy Efficiency Potential and Goals Study.[19] The AAEE projections include five savings scenarios, "Low", "Low-Mid", "Mid", "High-Mid", and "High". In general, the lowest savings scenario includes only the EE savings most certain to

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[16] See spreadsheets at http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/

[17] See pp. 127-130 of http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf

[18] The CPUC expects to continue to use the 2013 IEPR CED forecasts for consistency throughout the two year 2014 LTPP cycle

[19] Attached to the R.13-11-005 Assigned Commissioner's Ruling Amending Scoping Memorandum, and providing guidance on energy savings goals for program year 2015 http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=88661908

materialize while the highest savings scenario includes all EE potential including aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required. Some planning study types may utilize EE savings projections allocated at the transmission-level busbar, and/or daily and seasonal load-shape EE savings projections. Such studies may need to account for uncertainties regarding busbar location or load-shape impacts. In all studies, transmission and distribution loss-avoidance effects shall be accounted for.

Like the CED base forecasts, the CEC adopted the AAEE projection scenarios on December 11, 2013, and published final versions in spreadsheet format.[20] During 2013, the CEC, CPUC and CAISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the 2013 IEPR final report, published on January 23, 2013,[21] based on the IEPR record and in consultation with the CPUC and the CAISO, recommends using the Mid AAEE scenario for system-wide and flexibility studies for the CPUC 2014 LTPP and CAISO 2014-15 TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

For the purposes of calculating a statewide renewable net short to develop Renewable Portfolio Standard (RPS) portfolios, that calculation must also account for energy load reductions from incremental EE for all California Publicly Owned Utilities (POUs). That amount of incremental EE is the sum of the projections of each POU's incremental (uncommitted) EE reported by the POU on the CEC's S-2 supply forms.[22] The CEC projects 3,420 GWh of POU incremental EE savings in 2022 and recommends the same assumption in 2024. This number is used to calculate the statewide renewable net short in 2024.

The 2014 IEPR Update CED forecasts were made available in December 2014 and adopted by the CEC in January 2015. The 2014 IEPR Update aggregate projections of AAEE were not substantively changed from the 2013 IEPR. However, they have been scaled down slightly to account for the passage of time and the inclusion of more years of historical data in the base demand forecast. In addition, CEC staff intends to provide an updated allocation of EE savings projections down to the transmission level busbar to the CAISO for use in the 2015-16 TPP. As

[20] http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/Additional_Achievable_Energy_Efficiency/

[21] See pp. 127-130 of http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf

[22] http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/ See each POU's Uncommitted Energy Efficiency plans in the spreadsheet section "Generation/Production" on line item 3.

described earlier in this section, the 2015-16 TPP will continue to use the Low-Mid AAEE projection in local reliability studies.

4.1.5 Solar Photovoltaics

The CED forecasts embed the impacts of initiatives such as the California Solar Initiative, as well as the effects of retail rates and programs such as Net Energy Metering. As such, the default projection for behind-the-meter solar PV assumes no change from what the CED forecasts embed. Besides the default projection, planning scenarios may model a low or high projection of behind-the-meter solar PV ***incremental*** to the default projection. The low incremental projection is created by subtracting the self-generation PV projection embedded in the CED "Mid" load case (mid PV projection) from the self-generation PV projection embedded in the CED "Low" load case (high PV projection). The high incremental projection is created by subtracting the self-generation PV projection embedded in the CED "Mid" load case from the projection in the CPUC's study on the ratepayer impacts of Net Energy Metering (NEM) prepared by Energy and Environmental Economics (E3).[23] The NEM study result projects total cumulative behind-the-meter PV to reach 5,573 MW of installed capacity in 2020,[24] and CPUC staff linearly extrapolates this to 7,783 MW of installed capacity in 2024.

Although behind-the-meter PV is generally regarded as a demand-side resource, both the CED embedded PV and any incremental amounts will be modeled as supply resources, and modelers will adjust upward the load forecast as needed when accounting for CED embedded self-generation on the supply-side. This maintains consistency with modeling practice that treats these resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for. Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) and annual energy production (capacity factor) using values implied by the CED "Mid" load case embedded self-generation PV projection for each of the three major IOUs. The table below summarizes by IOU the implied peak impact factor and capacity factor.

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[23] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

[24] See the "Forecast" Tab in the E3 NEM Summary Public Model located at: http://www.cpuc.ca.gov/NR/rdonlyres/AD52FE7A-E283-4AB8-BCB2-87DF56D7443B/0/E3NEMSummaryTool.xlsm

Table 1: Small Solar PV Operational Attributes

Variable	PG&E	SCE	SDG&E	Average of all 3 IOUs
Peak impact factor	0.47	0.47	0.47	0.47
Capacity factor	0.18	0.19	0.20	0.19

The physical configuration of behind-the-meter (BTM) PV units influences the shape of hourly generation profiles and has material impact on the outcome of resource planning studies that inform the TPP and the LTPP. Two important physical attributes are the PV mounting type and the DC-AC inverter loading ratio. For BTM PV, the default assumption for mounting type is fixed-tilt, south-facing. The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher loading ratio tends to flatten or clip the production profile of a PV unit. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. For BTM PV, the default assumption for DC-AC inverter loading ratio is 1.2, which is consistent with the assumption used in the Transmission Expansion Policy Planning Committee (TEPPC) 2024 Common Case.[25]

4.1.6 Combined Heat and Power

The CED forecasts embed the impacts of initiatives such as the Self-Generation Incentive Program. As such, the default projection for behind-the-meter combined heat and power (CHP) assumes no change from what the CED forecasts embed. Besides the default projection, planning scenarios may model a low or high projection of behind-the-meter CHP ***incremental*** to the default projection. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report published in July 2012.[26] The low incremental projection is based on a CEC analysis of the "Base" projection of on-site generation from the ICF report. The high incremental projection is based on a CEC analysis of the "High" projection of on-site generation from the ICF report.[27] Note that since the projections in the ICF report are statewide, these numbers are disaggregated to planning areas for the three major IOUs using ratios derived from

[25] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

[26] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[27] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

the CEC analysis of the “Base” and “High” projections of on-site generation from the ICF report. This results in CAISO area 2024 incremental installed capacity projections of 955 MW in the low case, and 2,405 MW in the high case.

Similar to behind-the-meter PV, behind-the-meter CHP is generally regarded as a demand-side resource. As such, CHP embedded in the CED forecast, in addition to any incremental CHP amount, will be modeled as supply resources. Modelers will adjust the load forecast upward, as needed, when accounting for CED forecast embedded self-generation on the supply-side. This maintains consistency with modeling practice that treats these resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for. Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity and annual energy production using a 0.80 capacity factor.

4.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[28] demand response (DR) programs, in other words, those impacts are treated on the demand-side. These programs are generally non-event-based and/or tariff-based and include TOU rates, Permanent Load Shifting, and Real Time Pricing. Supply-side DR programs, which are generally event-based, price-responsive and reliability programs, are treated as supply resources.

There may be other effects that supply additional DR impacts, for example, a higher EV penetration could lead to charging models that can provide load shifting and frequency regulation by managing the charging times of an aggregate group of EVs. These speculative impacts are not accounted for at this time. Another expected future DR impact may come from defaulting residential customers to TOU rates. These impacts may be explored in the next major CEC IEPR planning cycle.

[28] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on “load-modifying” and “supply-side” DR programs.

4.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-side storage, as well as transmission-connected storage, within the Supply-side Assumptions section.

4.1.9 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. The factors are multiplied by demand-side resource projections to determine the avoided generation replaced by the presence of the demand-side resource.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications for existing or future contracts. To the extent a specific projected resource is not available; the analysis assumes an electrically equivalent resource will be available.

All supply-side resources should be categorized either as within a specific local area, as a generic system resource, or as out-of-state. Resources should be accounted for in terms of their most current net qualifying capacity (NQC). For purposes of constructing simple annual load and resource tables, August NQC values will be used. In the absence of a NQC, a resource's expected NQC should be based on its expected installed capacity adjusted for the peak impact value of that technology type. To the extent that NQC accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP. For variable resources, methods that can forecast production based on a variety of conditions are preferred to utilizing single point or year assumptions. For example, 8760 hour generation profiles for variable resources are used in production simulation model analyses. These profiles may also be used in CAISO TPP studies to determine output levels of these resources corresponding to the load levels (peak, off-peak, partial peak, and light load base cases) of the applicable studies. The Effective Load Carrying Capability (ELCC) method of assigning capacity value to wind and solar resources is expected to become available for the next cycle of developing planning assumptions. At this time, no degradation of resource production over time is accounted for in these planning assumptions.

4.2.1 Existing Resources

The capacities of existing resources shall be the monthly NQC values found in the 2014 Resource Adequacy compliance year NQC list.[29] The CAISO and CPUC both publish these lists annually on their respective websites.

4.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[30] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.[31]

4.2.3 Combined Heat and Power

Resources identified here export electricity to the grid. The Demand-side Assumptions section discusses resources that provide on-site energy. The default projection for exporting CHP assumes no net growth. Planning scenarios that model a higher penetration of exporting CHP shall add either a low or a high incremental projection of growth. ICF International conducted a

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[29] *See* Resource Adequacy Compliance Materials at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[30] http://www.energy.ca.gov/sitingcases/all_projects.html

[31] The Oakley power plant project was approved by the CPUC but recently annulled by the California Court of Appeal: http://www.courts.ca.gov/opinions/documents/A138701.PDF Therefore, Oakley will not be assumed as a conventional resource addition. During the second year of the LTPP cycle, CPUC staff expects to facilitate additional studies with varying additional resource options to determine the best way to fill any need found from studies conducted during the first year of the LTPP cycle. At that time, there may be an opportunity to explore the efficacy of the Oakley power plant in meeting identified needs.

policy analysis of CHP resources through 2030 and produced a report in July 2012.[32] The low incremental projection is based on a CEC analysis of the "Base" projection of exporting CHP from the ICF report. The high incremental projection is based on a CEC analysis of the "High" projection of exporting CHP from the ICF report.[33] Note that since the projections in the ICF report are statewide projections, these numbers are adjusted downward by a factor of 0.8, approximately the CAISO area to statewide load ratio. This results in CAISO area 2024 installed capacity projections of 164 MW in the low case, and 1,855 MW in the high case.

Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity. These resources are assumed to be non-dispatchable by the CAISO.

4.2.4 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target[34] of 1,325 MW installed capacity of new energy storage units within the CAISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Storage operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. The default planning assumption for new storage capacity shall account for a conservative expected contribution to grid services and reliability from the storage procurement target in D.13-10-040. No further growth in new storage capacity is assumed post 2024.

<u>Assumptions about storage attributes and capabilities</u>

While all storage can provide energy services, that is, storage can charge during periods of low energy prices and discharge during periods of high energy prices, their ability to provide capacity and flexibility (load-following, ancillary services, etc.) depends on their visibility and controllability by the CAISO. Transmission-connected storage will likely interconnect to the system near transmission substations and be visible and controllable by the CAISO. Therefore,

[32] See Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[33] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

[34] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

all of the 700 MW of new transmission-connected storage described above is assumed to provide capacity and flexibility as a default.

The ability of distribution-connected storage to provide capacity and flexibility carries significant uncertainty, in part because this technology is new to the market, and in part because current policy and the CAISO market does not fully support the participation of distribution-connected resources. Therefore, only 50% of the 425 MW of new distribution-connected storage described above is assumed to provide capacity and flexibility as a default. This acknowledges that greater than zero percent but less than 100% of these resources are expected to provide such services.

The ability of customer-side storage to provide capacity and flexibility carries even higher uncertainty. Not only is the market new, but customer-side storage will likely be non-dispatchable by either the CAISO or the IOUs (absent significant policy and market changes) and it is unclear how much of customer-side storage will charge from the grid or on-site generation, and according to what schedule. Therefore, none of the 200 MW of new customer-side storage described above is assumed to provide capacity and flexibility as a default.

A limiting factor to the ability of storage to provide capacity during peak demand hours is the duration of sustained output. The CPUC factors in a resource's ability to sustain output for at least four hours when calculating NQC for Resource Adequacy purposes.[35] Therefore, storage resources that only have a depth of two hours should have their capacity value derated by half (50%) for purposes of power flow reliability studies. This accounts for the inability of such resources to sustain full output during the duration of system peak hours. Capacity values in Table 3~~Table 3Table 3~~ below reflect this adjustment.

Note that although there are limits on the amount of storage procurement assumed to provide capacity and flexibility as described above, all 1,325 MWs can provide energy services and will be modeled as such in studies involving production cost simulations. The capacity limitations described above applies to power-flow type studies conducted in the CAISO's TPP. The table below describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage described by D.13-10-040.

[35] See page 32 of http://www.cpuc.ca.gov/NR/rdonlyres/C61CB838-E9BB-4CE2-AEB3-63DB955E2EF8/0/RAWorkshopReport2004.doc

Table 3: Storage Operational Attributes

Values are MW in 2024	Transmission-connected	Distribution-connected	Customer- side
Total Installed Capacity	700	425	200
Amount providing capacity in power flow studies	560 *	170 *	0
Amount providing flexibility	700	212.5	0
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	256 ^	170	100
Amount with 6 hours of storage	124 ^	85	0
Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.			

***** This reflects a 50 % derating of capacity value of 2 hour storage due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.
^ This amount was adjusted down to reflect the assumption that the 40 MW Lake Hodges storage project satisfies the storage target for a portion of SDG&E's share of the target.

In the CAISO's TPP Base local area reliability studies, locations for this new storage capacity must be assumed. It is reasonable to assume that cost-effectiveness requirements for new storage capacity will lead to siting at the most effective locations to contribute to local area reliability. As the CAISO's technical studies in the 2014-15 TPP identify transmission constraints in the local areas, the CAISO will identify the effective busses for mitigating those constraints. The storage amounts providing capacity and flexibility identified in the table above will be distributed amongst effective busses within the local areas and modeled. These bus locations are potential development sites for storage and shall inform the actual procurement to meet the storage procurement target.

All energy storage described here is exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CED forecasts.

<u>Adjustments due to actual and expected storage projects</u>

The 50 MW of storage that D.13-02-015 ordered SCE to procure and the 25 MW of storage that D.14-03-004 ordered SDG&E to procure are assumed to count towards the D.13-10-040 storage procurement target and shall not be double counted. To the extent pending applications to fill procurement authorizations D.13-02-015 and D.14-03-004 include storage beyond the minimum requirements ordered in the decisions, such storage projects are also assumed to count towards the storage procurement target and shall not be double counted. Table 3 above does not include any adjustment to reflect storage procurement resulting from D.13-02-015 and D.14-03-004. See the discussion on pending applications in section 4.2.14 for further details.

The Lake Hodges storage project in the San Diego area counts as an existing resource within the Scenario Tool. This project is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target and Table 3 above reflects this. Specifically, Lake Hodges is a 40 MW project and is assumed to satisfy all of SDG&E's share of 6-hour transmission-connected storage target (16 MW target minus 16 MW from Lake Hodges) and most of SDG&E's share of 4-hour transmission-connected storage target (32 MW target minus the remaining 24 MW from Lake Hodges).

Alternative storage assumptions

The default planning assumptions accounting for the storage procurement target are admittedly conservative. For example, the assumption that half of distribution-connected storage and all of customer-side storage does not provide capacity or flexibility probably undercounts their value. The intention is to model the grid conservatively to start with in order to reveal potential reliability needs. Any revealed reliability needs will be used to inform how the storage procurement target actually gets implemented. To enable this, during the second year of the LTPP cycle, CPUC staff expects to facilitate additional flexibility studies with varying additional resource options to determine the best way to fill any flexibility need found from studies conducted during the first year of the LTPP cycle. If there is a need, CPUC staff may explore two additional resource options for storage in LTPP flexibility studies:

1. In addition to the default planning assumptions for new storage, add one or two new large-pumped hydro storage units, the exact MW amount depends on what the revealed need is. Note that according to D.13-10-040, the maximum size of pumped storage projects that count towards storage procurement target is 50 MW. Therefore if studies demonstrate that this additional resource option is the best way to fill any need, the LTPP proceeding will consider pumped storage projects larger than 50 MW in general solicitations for new capacity conducted by utilities.

2. In addition to the default planning assumptions for new storage, assume policy and market changes that enable a more complete contribution to grid services and reliability from new distribution-connected and customer-side storage. Additional storage beyond the storage procurement target may be assumed depending on what the revealed need is.

4.2.5 Demand Response

Demand response, or DR, (generally event-based price-responsive and reliability programs) that can be bid into CAISO market shall be accounted for as a supply-side resource[36]. Transmission and distribution loss-avoidance effects shall be accounted for. The most recent Load Impact reports[37] filed with the CPUC serve as the basis for DR planning assumptions. The Load Impact reports are published annually on April 1. In all types of system and local area resource planning studies, DR capacity shall be counted using the 1-in-2 weather year ex-ante forecast of monthly load impact, portfolio-adjusted. This is consistent with the capacity value of DR for Resource Adequacy. For the purpose of building load and resource tables, DR capacity shall be counted using the 1-in-2 weather year condition ex-ante forecast of August load impact, portfolio-adjusted. For the purpose of building detailed profiles of DR load impact in system and local area planning models, DR is assumed available at times of system stress, subject to program operating constraints but not limited to operating hours specified in Resource Adequacy accounting rules. Program operating constraints are obtained from the utilities' Load Impact reports and tariffs for each program.[38] The ex-ante load impacts for the operating hours specified in Resource Adequacy accounting rules, by program, are found in the Load Impact reports. For modeling purposes, programs with operating hours beyond hour

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[36] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs.

[37] To access IOU Load Impact reports, please see:
PG&E: https://www.pge.com/regulation/DemandResponseOIR/Other-Docs/PGE/2013/DemandResponseOIR_Other-Doc_PGE_20130402_269621.pdf
SCE: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/62A8F5E44C447F0688257B410052EC7B/$FILE/R.07-01-041_DR+OIR-SCE+DR+Portfolio+Summary+2012+-+Final.pdf
SDG&E: http://www.sdge.com/regulatory-filing/742/rulemaking-regarding-policies-and-protocols-demand-response-load-impact

[38] To access IOU demand response tariffs, please see:
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/
SDG&E: http://www.sdge.com/save-money/demand-response/overview

ending 18 shall be triggered at $600/MWh and all other programs shall be triggered at $1000/MWh.

In the CAISO's TPP Base local area reliability studies, only capacity from DR programs that can be relied upon to mitigate "first contingencies", as described in the 2012 LTPP Track 4 planning assumptions[39], are counted. DR that can be relied upon to mitigate first contingencies in local reliability studies participates in, and is dispatched from, the CAISO market in sufficiently less time than 30 minutes[40] from when it is called upon.

There is uncertainty as to what amount of DR can be projected to meet this criteria within the TPP planning horizon given that few current programs meet this criteria and the current DR Rulemaking R.13-09-011 expects to restructure DR programs to better meet CAISO operational needs and has already produced two major policy decisions towards that goal.[41] The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but CAISO has several tasks it must complete in order to make integration of DR possible.

The 2012 LTPP Track 4 planning assumptions estimated that approximately 200 MW of DR would be available to mitigate first contingencies within the combined LA Basin and San Diego local reliability areas by 2022. The 2014 LTPP planning assumptions, however, estimates that approximately 1,100 MW would be available to mitigate first contingencies within the combined LA Basin and San Diego local reliability areas by 2024. Staff developed this latter estimate by screening DR projections in the Load Impact reports for programs that deliver load reductions in 30 minutes or less from customer notification. The table below identifies for each IOU the programs and capacities that meet this criteria.

[39] See Attachment A of Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge in R.12-03-014, May 21, 2013, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF

[40] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

[41] Commission Decision 14-03-026 approved the bifurcation of DR programs into two categories: Supply DR (DR that is integrated into CAISO markets and dispatched when and where needed) and Load-Modifying DR (DR that is not integrated into CAISO markets and used to modify the demand forecast). Decision 14-12-024 clarified that complete bifurcation will occur by the beginning of 2018.

Table 4: DR Capacity in Local Area Reliability Studies

"First Contingency" DR Program MW in 2024 using 1-in-2 weather year ex ante impacts	PG&E	SCE	SDG&E
Base Interruptible	287	627	1
Agricultural Pumping Interruptible	n/a	69	n/a
AC Cycling Residential	82	298	12
AC Cycling Non-Residential	1	76	3

Given the uncertainty as to what amount of DR can be relied upon for mitigating first contingencies, the CAISO's 2014-15 TPP Base local area reliability studies examined two scenarios, one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions, shown above. Staff expects the same two scenarios to be examined in the 2015-16 TPP, except that the latter scenario should be updated to be consistent with the latest Load Impact reports filed with the CPUC on April 1, 2014 under R.13-09-011.

To the extent technical studies require estimates of DR capacity at individual transmission-level busbars, DR capacity will be allocated to busbar using the method defined in D.12-12-010, or specific busbar allocations provided by the IOUs. For the 2014-15 TPP, the DR amounts in Table 4~~Table 4Table 4~~ were the basis for busbar allocations provided from the IOUs to the CAISO. In November 2014, the IOUs updated the busbar allocations to be consistent with the latest available Load Impact reports (April 1, 2014). CPUC staff expects the IOUs to provide these updated busbar allocations to the CAISO for use in the 2015-16 TPP. CPUC staff submitted comments identifying the updated busbar allocations in response to the CAISO's request for input on demand response assumptions for the CAISO's 2015-16 Unified Planning Assumptions.[42]

The default planning assumptions accounting for DR capacity are admittedly conservative given CPUC expectations to restructure programs and expand capacity in the DR Rulemaking R.13-09-011. However, rather than speculate what the outcome of the DR Rulemaking might be, the default planning assumptions presume the continuation of the utilities' existing DR programs.

[42] Comments were submitted via this CAISO Market Notice: http://www.caiso.com/Documents/StakeholderInputfor2015-2016UnifiedPlanningAssumptions.htm

The intention is to model the grid conservatively to start with in order to reveal potential reliability needs. Any revealed reliability needs will be used to inform new DR program development/procurement. To enable this, during the second year of the LTPP cycle, CPUC staff expects to facilitate additional flexibility studies with varying additional resource options to determine the best way to fill any flexibility need found from studies conducted during the first year of the LTPP cycle. If there is a need, CPUC staff may explore an additional resource option in LTPP flexibility studies that expands DR capacity such that the total DR capacity is equal to 5% of the forecasted managed 1-in-2 weather year system peak demand by 2021, and reaches 10% of the forecasted managed 1-in-2 weather year system peak demand by 2030. The expanded DR capacity shall be assumed available to hour ending 21, triggered at $600/MWh, and use limited to 20 hours per month. These parameters may be adjusted depending on the revealed need.

4.2.6 RPS Portfolios

Overview

The forecast of renewable resources is developed using the Renewable Portfolio Standard (RPS) Calculator. The RPS Calculator uses public data to develop portfolios of renewable resources to use for planning studies. Since a large portion of the cost associated with renewables is tied to the cost of transmission capacity needed to deliver the power to market, the RPS Calculator optimizes existing transmission and, when necessary, optimizes the use of minor upgrades to existing transmission lines as well as the use of new transmission lines. As such, when two similar resources are incorporated into the RPS Calculator, it selects the resource with access to current transmission capacity over the resource that requires new transmission capacity, thereby minimizing additional transmission cost. The RPS Calculator also incorporates four policy priority metrics: permitting (i.e. quickest on-line time), lowest cost, least environmentally harmful and commercial interest. The weight applied to each metric, in addition to the overall renewable net short (RNS) need, impacts the make-up of a given portfolio. The portfolios created for the 2014-2015 TPP and LTPP reflect the application of a 70% weight to the Commercial Interest score and a 10% weight to the Environmental, Permitting, and Cost scores.

CPUC & CEC Collaboration

CPUC and CEC staff collaboratively developed the RPS portfolios, with CEC staff providing to CPUC staff its most recent IEPR CED retail sales forecast, demand side management assumptions, environmental scores, and online renewable generation, which CPUC staff uses to, among other things, calculate each portfolio's RNS. Once the RPS portfolios are created and vetted via a public stakeholder process, the CPUC and CEC jointly submit the portfolios to the CAISO for incorporation into the CAISO's Transmission Planning Process (TPP) studies. The CAISO's transmission modeling, which is more detailed than the modeling performed by RPS Calculator, determines what, if any, transmission improvements are needed in order to bring the projects included in the portfolios to market. The CPUC also sends to the CAISO any additional portfolios it needs to conduct LTPP specific studies.

Portfolio Selection Process

The RPS Calculator first selects resources assumed as very likely to be constructed when filling a given RNS need. Such resources are referred to, interchangeably, as the "Discounted Core" projects or "commercial" projects. For a project to be included into the Discounted Core it must meet two milestones: (1) have a CPUC approved Power Purchase Agreement, and (2) have a complete (i.e. data adequate) application for a major environmental permit. Projects that do not meet these criteria are referred to as "generic" projects. These are the same criteria that were applied to the renewable resources in the 2010 LTPP RPS portfolios and the 2012-13 TPP RPS portfolios. The weights applied to each metric – Commercial Interest, Environmental, Permitting, and Cost – in addition to the given sales forecasts, demand side management assumptions, and transmission assumptions, drives a portfolio's outcome.

For planning purposes, staff assume that an existing renewable generation facility located in California that has a contract that expires before its expected retirement age remains in service until its scheduled retirement age. Such a resource does not count toward any specific Load Service Entity's RPS, but it is nonetheless included in the calculation of the expected renewable supply and is therefore counted toward filling the RNS.

Variations of the RPS Calculator

CPUC staff published two variations of the RPS Calculator: the "regular" Calculator, which gives preference to a modest number of distributed photovoltaic generation (DG) projects near load, and a "high DG" Calculator, which gives preference to greater number of DG projects near load.[43] For the CAISO's 2014-15 TPP, CPUC staff created a third variation of the RPS Calculator that models different transmission availability in the Imperial CREZ than is modeled in the "regular" RPS Calculator. The portfolio created with this variation of the RPS Calculator is referred to as the "33% 2024 Mid AAEE (sensitivity)" portfolio.

Planned RPS Calculator Overhaul

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[43] The RPS Calculator may be downloaded here: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

In light of the continually increasing renewable technological potential and their respective cost-effectiveness, some costs and performance assumptions embedded in the RPS Calculator are now outdated, which limits the RPS Calculator's robustness when modeling RPS targets greater than 33%. The cost and performance assumptions are being updated in a "new" version of the RPS Calculator, as part of CPUC's RPS proceeding (R.11-05-005). The "new" RPS Calculator – referred to as the RPS Calculator version 6 (v6) – will be vetted via a stakeholder process, beginning at a February 10-11, 2015 scheduled workshop[44]. The development of the RPS Calculator v6 is scheduled to be completed in time to inform the RPS portfolios for use in the 2016-2017 LTPP, as well as the 2016-17 CAISO TPP. The new RPS Calculator will be fundamentally redesigned so that resource options will be added to a portfolio based not on their individual value-vs-cost alone, but rather, on how they impact the value-vs-cost of an entire portfolio since every resource impacts this value-vs-cost relationship differently when added to, or subtracted from, the system. The new, more robust, RPS Calculator will be especially useful when considering RPS goals in excess of the current 33% target. The collaboration process, described above, between the CPUC and CEC staff may change in light of the development of the RPS Calculator v6.

<u>The Scenario Tool</u>

For the purposes of creating a load and resource table for 2014-2034, the Scenario Tool maintains an approximation of the capacity value (NQC value) of new RPS resources throughout the planning horizon for each of the defined planning scenarios. In order to develop this approximation, the (old) RPS Calculator is run twice for each portfolio: once with a 2024 RNS target year and again with a 2034 RNS target year. The NQC values produced by the 2024 RNS target year run of the Calculator are used directly by the Scenario Tool for years 2014-2024. For years 2025-2034, the difference in the amount of NQC that the RPS Calculator produces for the 2024 RNS target year versus the 2034 RNS target year is divided by 10 (the extrapolated time horizon). This incremental NQC amount is added each year from 2025-2034 in the Scenario Tool.

The table below summarizes seven different RPS portfolios that will be modeled in the different planning scenarios described later in this document.

[44] See RPS workshop Ruling via this link:
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M143/K990/143990469.PDF

Table 5: RPS Portfolio Summary

Portfolio Name	Base Demand Forecast For RNS	Demand Side Management Assumptions For RNS	Variation of RPS Calculator	Study in which Portfolio Is Used ^	Base Demand Forecast for Study
33% 2024 Mid AAEE *#	Mid(1:2)	Mid AAEE	Regular	TPP #1b, #1c TPP #1d LTPP #1, #1e TPP #1a	Mid(1:5) peak Mid(1:2) 8760 Mid(1:2) 8760 Mid(1:10) peak
33% 2024 LowMid AAEE *	Mid(1:2)	LowMid AAEE	Regular	TPP #1a	Mid(1:10) peak
33% 2024 High Load Mid AAEE	High(1:2)	Mid AAEE	Regular	LTPP #2	High(1:2) 8760
33% 2024 Mid AAEE (sensitivity) *	Mid(1:2)	Mid AAEE	Regular (sensitivity)	TPP #1c TPP #1d	Mid(1:5) peak Mid(1:2) 8760
High DG 33% 2024 Mid AAEE + DSM *#	Mid(1:2)	Mid AAEE, High Inc Sm PV, Low Inc CHP	High DG	TPP #1c TPP #1d, LTPP #5	Mid(1:5) peak Mid(1:2) 8760
High DG 40% 2024 Mid AAEE	Mid(1:2)	Mid AAEE	High DG	LTPP #4	Mid(1:2) 8760
High DG 40% 2024 HighMid AAEE + Higher DSM	Mid(1:2)	HighMid AAEE, High Inc Sm PV, High Inc CHP	High DG	LTPP #3	Mid(1:2) 8760

* These portfolios were used in the CAISO's 2014-15 TPP.

These portfolios are intended for use in the CAISO's 2015-16 TPP.

^ The numbering in this column refers to the Scenario numbers as described in the Scenario Matrix, see Table 11 of this document.

See the Appendix of this document for tables describing the makeup of the RPS portfolios by Competitive Renewable Energy Zones (CREZs) and by technology type.

4.2.7 RPS Portfolios for the 2015-16 TPP

The RPS portfolios that are expected to be studied in the CAISO 2015-16 TPP will be the "33% 2024 Mid AAEE" and the "High DG 33% 2024 Mid AAEE + DSM" portfolios that were used in the 2014-15 TPP – renamed the "33% 2025 Mid AAEE" and the "High DG 33% 2025 Mid AAEE + DSM" portfolios for the 2015-16 TPP. These two portfolios include updated locational information for the distributed generation (DG)[45] in the portfolios. The "33% 20254 Mid AAEE" portfolio will be used in both system and local reliability studies in the 2015-16 TPP, while both portfolios will be studied in the 2015-16 TPP policy and economic studies and CAISO's DG deliverability studies. These updated RPS portfolios were formally submitted to the CAISO on March 11, 2015.

Transmission Capacity Update Pursuant to 2014-15 TPP Adopted Transmission Plan

On March 20, 2015, CPUC and CAISO staff determined that updates in transmission capacity resulting from the CAISO 2014-15 TPP studies materially affect the two RPS portfolios that had been submitted to the CAISO on March 11, 2015. An agreement was reached to make a simple, but important update to the transmission capacity assumed in the RPS calculator (v.5) and to re-run the "33% 2025 Mid AAEE" RPS portfolio in order to reflect the latest CAISO transmission capacity findings. This update changed the transmission capacity modeled in the RPS calculator in two of the Competitive Renewable Energy Zones (CREZs), as follows:

1) The available existing transmission capacity assumed in the Kramer CREZ is now 250 MW (up from 62 MW).

2) The Imperial CREZ with minor upgrades now has 1750 MW of capacity (up from 1000 MW).

The changed transmission capacity assumed in these two CREZs changed the composition of the "33% 2025 Mid AAEE" RPS portfolio by decreasing the generic projects in the Kramer CREZ and increasing the generic projects in the Imperial CREZ. The RPS portfolio incorporating this change was formally submitted to the CAISO via a revised TPP transmittal letter[46], dated April 29, 2015. The Appendix of this document provides a summary table (Table 15) showing the changed composition of the "33% 2025 Mid AAEE" RPS portfolio by CREZs and by technology type.

4.2.8 Technical Attributes of Solar PV projects

The physical configuration of solar PV projects influences the shape of their hourly generation profiles and has material impact on the outcome of resource planning studies that inform the

[45] The update to DG locational information for transmission planning purposes consists of updated latitude, longitude, and WECC bus I.D. Only a subset of the DG projects' locational information was able to be updated with actual DG project information.

[46] The transmittal letter can be viewed here: Revised RPS Scenario Transmittal Letter

LTPP. Two important physical attributes are the mounting-type and the DC-AC inverter loading ratio. Mounting-type includes the following:

- Fixed-tilt: stationary panels tilted, south-facing
- Tracking, 1-axis: panels track the sun on a single axis from East to West
- Tracking, 2-axis: panels track the sun on a dual axis (these projects are rare)[47]

The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher ratio tends to flatten or clip the production profile of a PV project. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. The aggregate assumptions for mounting-type and inverter loading ratio (ILR) for all future studies within the 2014 LTPP proceeding shall be consistent with the following table.

Table 6: IOU-contracted solar PV capacity (MW) and capacity-weighted average ILR, by mounting-type

	PG&E	SCE	SDG&E
Fixed-tilt capacity	2,043	876	395
Fixed-tilt ILR	1.26	1.24	1.29
Tracking capacity	1,406	3,334	938
Tracking ILR	1.28	1.31	1.29

The table above summarizes the contracted solar PV capacity (as of June 2015) for each of the three major IOUs and the capacity-weighted average inverter loading ratio separated by mounting-type.[48] "IOU-contracted" means the project has a CPUC-approved power purchase contract and it can be an existing online project or a project still under development. In the latter case, these projects are generally the "commercial" projects that the RPS Calculator uses to fill a renewable net short (see section 4.2.6 on RPS portfolios). Because these projects have

[47] Dual-axis tracking solar PV projects represent a tiny portion of tracking projects CAISO-wide, just 12 MW of capacity out of over 5,600 MW of IOU-contracted projects. For simplicity, the tables below treat dual-axis projects as if they were single-axis projects.

[48] This data was aggregated from individual project data obtained from the CPUC Energy Division's RPS Contract Database (formerly known as Project Development Status Reports), June 2015 vintage, and data request responses from each IOU that provided physical attribute information for all IOU-contracted projects. Projects that were from either of these sources are either existing online projects or projects in development assumed to meet the criteria for "commercial" projects in the RPS Calculator. Some of these projects are in fact IOU-owned. The aggregated data does not identify market-sensitive information about individual solar PV projects.

a CPUC-approved power purchase contract, their physical attributes are known and the projects are likely to be completed successfully.

The "generic" projects that the RPS Calculator uses to fill a renewable net short do not yet have CPUC-approved power purchase contracts and therefore have higher uncertainty as to the actual physical attributes of the projects that would ultimately get developed. For planning purposes, however, studies need to assume a mounting-type and inverter loading ratio for "generic" projects. The trends of mounting-type and inverter loading ratio in the most recent IOU-contracted projects can be used as a proxy for the likely physical attributes of "generic" projects. The table below categorizes IOU-contracted projects by online year and identifies the amount of each mounting-type by capacity and percentage of total capacity.

Table 7: IOU-contracted solar PV capacity (MW) grouped by mounting-type and online year

	any year	%	2014 or later	%	2015 or later	%
PG&E						
Fixed-tilt	2,043	59%	1,560	61%	176	17%
Tracking	1,406	41%	1,000	39%	831	83%
SCE						
Fixed-tilt	876	21%	836	21%	525	15%
Tracking	3,334	79%	3,215	79%	3,040	85%
SDG&E						
Fixed-tilt	395	30%	17	3%	17	7%
Tracking	938	70%	552	97%	225	93%
3 IOUs						
Fixed-tilt	3,315	37%	2,414	34%	718	15%
Tracking	5,678	63%	4,767	66%	4,097	85%

The newest projects (online in 2015 or later) are primarily~~mostly~~ tracking~~ mounting-type~~. Based on this trend, "generic" projects selected by the RPS Calculator shall be assumed 15% fixed-tilt and 85% tracking. There does not appear to be a clear difference in inverter loading ratios for newer vs. older projects. Therefore, "generic" projects shall be assumed to have inverter loading ratios similar to the capacity-weighted average of all IOU-contracted projects. The table below summarizes the mounting-type and inverter loading ratio assumptions for "generic" (i.e. not yet contracted) projects selected by the RPS Calculator to fill a renewable net short in a given planning scenario. The percentage represents the share of all generic solar PV projects.

Table 8: Generic solar PV project mounting-type and ILR assumptions

	PG&E	SCE	SDG&E
Fixed-tilt % share	15%	15%	15%
Fixed-tilt ILR	1.26	1.24	1.29
Tracking % share	85%	85%	85%
Tracking ILR	1.28	1.31	1.29

~~4.2.8~~4.2.9 Nuclear Retirements

Diablo Canyon Power Plant (DCPP) is assumed to have obtained renewal of licenses to continue operation beyond 2025 by default. The alternative assumption is retirement in 2023, in order to explore the impact of a loss of DCPP within the first 10 year planning horizon. These assumptions should be informed by AB 1632 (Blakeslee, Chapter 722, Statutes of 2006) seismic and related studies around the DCPP area.

~~4.2.9~~4.2.10 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using OTC technology (except DCPP) retire according to the current State Water Resources Control Board (SWRCB) OTC compliance schedule.

Moss Landing

The original compliance date for Moss Landing under the OTC compliance schedule was December 31, 2017. However, a settlement agreement signed by Dynegy (the owner of Moss Landing) and the SWRCB staff in October, 2014 extended this compliance date to December 31, 2020 for Units 1 and 2 and Units 6 and 7. This OTC amendment, per the settlement agreement, was approved by the SWRCB on April 7, 2015 and is now in effect. However, the path to compliance for all of these units remains unclear. ~~To date, staff does not know whether there are plans to retrofit the Moss Landing facility in order to continue operating it beyond December 31, 2020 as a SWRCB OTC policy compliant unit. As such, for LTPP planning assumptions purposes~~ The plant owner stated their intent to install technology on Units 1 and 2 which will allow them to continue operating. ~~In the spirit of using conservative planning assumptions,~~ Therefore, ~~s~~staff assumes that by December 31, 2020 Units 1 and 2 will be successfully retrofitted and that Units 6 and 7 will retire.~~all four of the Moss Landing units will retire by December 31, 2020.~~

~~4.2.10~~4.2.11 Renewable and Hydro Retirements

Retirements are based on facility age as a proxy for a unit reaching its operational lifetime. Operational history will not be considered in this planning cycle. A "Low" level of retirement assumes these resource types stay online unless there is an announced retirement date. A "Mid" level assumes solar and wind resources retire at age 25, other non-hydro renewable technologies retire at age 40, and hydro resources retire at age 70. A "High" level assumes solar and wind resources retire at age 20, other non-hydro renewable technologies retire at age 25, and hydro resources retire at age 50. Note that retirement assumptions based on facility age carry a wide range of uncertainty. The default assumption for planning studies is a "Low" level of retirement for renewable and hydro resources.

~~4.2.11~~4.2.12 Other Retirements

Retirements are based on facility age as a proxy for a unit reaching its operational lifetime. Operational history will not be considered in this planning cycle. A "Low" level of retirement assumes "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes retirement based on resource age of 40 years or more. A "High" level assumes retirement based on resource age of 25 years or more. Note that retirement assumptions based on facility age carry a wide range of uncertainty. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Energy Division will periodically request confidential procurement data from the utilities to screen for such facilities. "Other" includes all resources whose retirement assumptions are not explicitly described above, for example peakers and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

Long Beach Peakers

From a technical and operational perspective, the Long Beach peaker plants can remain in operation at least through 2025 due to recent refurbishments. These peaker plants' economic lifespan, however, depends on whether this facility can successfully re-contract its power once its current contract expires in 2017. The planning assumptions in studies informing D.14-03-004 and the 2015-16 CAISO TPP assumed that the Long Beach Peakers would retire at the end of its current contract. In contrast, the retirement assumption specified in the Rulings on 2014 LTPP planning assumptions dated Mar 4, 2015 assumed that the Long Beach Peakers would remain online at least through 2025. In order to align with the retirement assumption used in

D.14-03-004 and the 2015-16 CAISO TPP, the 2014 LTPP planning assumptions now assume that the Long Beach Peakers will retire by **December 31, 2017**.

~~4.2.12~~4.2.13 Imports

For the purposes of load and resource tables, i.e. the Scenario Tool, the default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area, and is published on its website annually.[49] In 2013 this value was 13,396 MW. In the Scenario Tool, the 13,396 MW value is used throughout the planning horizon. An alternative assumption is historical expected imports as calculated by the CEC.[50]

Technical planning studies require a more nuanced approach to accounting for imports. In the 2010 and 2012 LTPP studies the CAISO used a tool to calculate California state and CAISO area maximum imports. The tool calculates import limits for each scenario being studied based on inertia changes in the Southern California Import Transmission (SCIT) area due to increased penetration of renewable resources and retirement of generation resources with inertia. The CAISO will update the tool and use it for the LTPP studies envisioned by this document.

For technical planning studies requiring information about infrastructure, resources, and loads outside of the CAISO area, the latest Transmission Expansion Policy Planning Committee (TEPPC) data should be used, for example, the TEPPC 2024 Common Case generation table.[51]

Resource planning studies conducted for the LTPP proceeding during 2014 were largely based on the CAISO's implementation of the PLEXOS production cost simulation model, which relied on data from a pre-release version of the TEPPC 2024 Common Case. The final version of the TEPPC 2024 Common Case is version 1.5.[52] Any additional modeling conducted to inform the 2014 LTPP proceeding should incorporate the final version of the TEPPC 2024 Common Case (v1.5).

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[49] http://www.caiso.com/Documents/2014Assigned-UnassignedRA_ImportCapability-BranchGroups-AfterStep6.pdf

[50] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

[51] *See* Data/Surveys" at http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

[52] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

~~4.2.13~~4.2.14 Existing Procurement Authorizations

Existing procurement authorizations of new generation and transmission assets shall be accounted for as a default planning assumption. The transmission projects approved by the CAISO Board in the 2013-14 TPP shall be included in all planning scenarios. The transmission projects approved by the CAISO Board in the 2014-15 TPP may inform any supplemental LTPP studies conducted in 2015. For new generation assets, planning assumptions are informed by LCR procurement authorizations in CPUC decisions D.13-02-015, D.13-03-029, and D.14-03-004, as described in detail below.

Planning Assumptions Made Without Pending Applications Data

For technical studies conducted in 2014, data from pending applications to fill the above LCR procurement authorizations were not available. Due to the uncertainty over what types of resources would actually be procured and the range of procurement allowed by the decisions, only a subset of LCR procurement from D.13-02-015, D.13-03-029, and D.14-03-004 were accounted for in LTPP planning scenarios studied in 2014, as shown in the table below. Remaining LCR procurement authorizations of between 15 and 90 MW in Big Creek/Ventura, between 850 and 1450 MW in W. LA Basin, and between 475 and 775 MW in San Diego were not modeled in LTPP planning scenarios studied in 2014. The technical studies assumed generic resources located at existing sites to facilitate modeling and did not intend to prejudge application approval or speculate on actual resource type or location.

Table 9: Procurement authorization assumptions with limited data

Decision	Capacity (MW)	Assumed online	Location	Description
D.13-02-015	900	2019	W. LA Basin	Combined cycle gas turbine
	100	2019		Peaker gas turbine
	200	2019	Big Creek/Ventura	Peaker gas turbine
	50 [53]	2019	W. LA Basin	Battery storage – transmission-connected
D.13-03-029	300	2016	Pio Pico site	Peaker gas turbine
	13	2014	San Diego	Net capacity increase at "MMC Escondido aggregate"
D.14-03-004	25 [54]	2019	San Diego	Battery storage – transmission-connected

Planning Assumptions Made With Pending Applications Data

Data from pending applications to fill the above existing LCR procurement authorizations became available in late 2014. The pending applications for LCR procurement include A.14-11-012 and A.14-11-016 filed by SCE, and A.14-07-009 filed by SDG&E. With this additional information, supplemental LTPP studies that may be conducted in 2015 can more completely model the resources represented by the existing LCR procurement authorizations. The complete set of planning assumptions for existing LCR procurement authorizations are specified in the table below and should be used for all future studies conducted in the remainder of the 2014 LTPP planning cycle. These assumptions should also inform CAISO TPP studies and be used to offset any need for new generation or transmission.

[53] The 50 MW storage amount is listed here for completeness, but should not be modeled twice (double counted) as part of D.13-02-015 assumptions and as achievement of the storage procurement target in D.13-10-040.

[54] The 25 MW storage amount is listed here for completeness, but should not be modeled twice (double counted) as part of D.14-03-004 assumptions and as achievement of the storage procurement target in D.13-10-040.

Table 10: Procurement authorization assumptions with pending applications data

Decision	Capacity (MW)	Assumed online	Location	Description
D.13-02-015, D.14-03-004	640	2021	Long Beach	Combined cycle gas turbine
	644	2021	Huntington Beach	Combined cycle gas turbine
	98	2021	Stanton	Combined cycle gas turbine
	124	2021	W. LA Basin	Energy efficiency
	75	2019	W. LA Basin	Demand response
	38	2019	W. LA Basin	Distributed generation solar PV
	135 [55]	2019	W. LA Basin	Battery storage – BTM
	29	2020	W. LA Basin	Thermal storage – BTM
	100	2019	Long Beach	Battery storage – transmission-connected
	6	2021	Big Creek/Ventura	Energy efficiency
	6	2018	Big Creek/Ventura	Distributed generation solar PV
	262	2021	Big Creek/Ventura	Peaker gas turbine
D.13-03-029	300	2016	Pio Pico site	Peaker gas turbine
	13	2014	San Diego	Net capacity increase at "MMC Escondido aggregate"
D.14-03-004, D.15-05-051	~~600~~500	2018	Encina site	Peaker gas turbine
	25 [56]	2019	San Diego	Battery storage – transmission-connected

[55] A portion of the 264 MW of storage procured for D.13-02-015 and D.14-03-004 and shown in this table also counts toward achievement of the storage procurement target in D.13-10-040. The 264 MW shown here is listed for completeness, but should not be modeled twice (double counted).

[56] The 25 MW storage amount is listed here for completeness, but should not be modeled twice (double counted) as part of D.14-03-004 assumptions and as achievement of the storage procurement target in D.13-10-040.

Note that the table above still does not encompass the entirety of existing LCR procurement authorizations, mostly because SDG&E has not yet filed an application for the preferred resources portion of its authorization. To the extent supplemental LTPP studies conducted in 2015 investigate any identified need, the remaining LCR procurement authorizations not included in the table above should be added to the studies before considering any other resources.

The energy efficiency, demand response, and distributed generation resource assumptions listed in Table 10 above are incremental LCR procurement and therefore assumed to be incremental to the other energy efficiency, demand response, and distributed generation assumptions described earlier in this document.

Resources located at the Encina site

NRG submitted a Petition to Amend to the CEC on May 2, 2014 to replace all five units plus a small combustion turbine at the Encina site with a 600 MW simple-cycle combustion gas turbine power plant. Concurrently, SDG&E submitted application A.14-07-009 to the CPUC for approval of a power purchase agreement with NRG. On May 21, 2015, the CPUC adopted Decision D.15-05-051 which conditionally approved 500 MW of the 600 MW originally ~~requested~~authorized and directs SDG&E to fill the residual 100 MW of procurement authorized by D.14-03-004 with preferred resources or energy storage. Table 10 above includes the approved 500 MW but does not include the residual 100 MW because the likely composition of those 100 MW is unknown at this time.

Interaction of LCR procurement and storage target

Note that some of the storage projects in applications to fill existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target and are noted as such in the table above. Technical studies shall not double count these resources. Table 3 in the storage section of this document does not include any adjustment to reflect how existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target. The Scenario Tool (version 4 and later) illustrates the available capacity from assumed LCR procurement and reconciles how some of this LCR procurement satisfies a portion of the storage procurement target.

SCE's share of the D.13-10-040 storage procurement target for behind-the-meter (BTM) storage is 85 MW. However, SCE proposes to procure about 164 MW of BTM storage in its LCR procurement applications. This exceeds its 85 MW target (per D.13-10-040) for BTM storage by 79 MW. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for BTM storage is completely filled by its proposed LCR procurement. Note that all of the 164 MW of BTM storage represented by SCE's LCR application should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements. This supersedes the general assumption described in storage section 4.2.4 that BTM storage would not be able to provide capacity in power flow studies.

SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is 310 MW. However, SCE proposes to procure about 100 MW of transmission-connected storage in its LCR procurement applications. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its proposed LCR procurement of 100 MW and the remaining share of the storage procurement target is 210 MW.

SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is 80 MW. After accounting for existing project Lake Hodges, the remaining share is 40 MW (see storage section 4.2.4). However, D.14-03-004 requires SDG&E to procure 25 MW of storage that can meet LCR needs. Therefore technical studies should assume that SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its required LCR procurement of 25 MW and the remaining share of the storage procurement target is 15 MW. Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements. This supersedes the general assumption described in storage section 4.2.4 that 2-hour storage capacity value should be derated by 50% in power flow studies due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.

4.3 Other Assumptions

4.3.1 The Second Planning Period

Planning studies which target years within the second planning period (2025-2034) will use simplified planning assumptions.[57] Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

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[57] The CAISO 2015-16 TPP will include local reliability studies for year 2025 of a limited number of local areas. Improved detailed projections for base demand (2014 IEPR Update CED forecast), AAEE (updated allocation to busbar with additional historical data), and demand response (updated allocation to busbar based on April 2014 Load Impact reports), as described earlier in this document, are available for use in the 2015-16 TPP studies.

- Net (managed) load growth will be extrapolated using the average, annual compound growth rate from the prior period. Only the net load will be extrapolated (i.e. the forecast load, after demand side adjustments such as AAEE), rather than extrapolating individual load or demand assumptions. The formula for calculating the growth rate is:

$$GrowthRate = \left(\frac{NetLoad_{2024}}{NetLoad_{2014}}\right)^{\frac{1}{(2024-2014)}} - 1$$

where Net Load is the gross load forecast minus AAEE. This annual growth rate is then applied to the 2024 Net Load to calculate the Net Load for 2025-2034.

- Resource retirements will be calculated based on resource age or other characteristic, as described for the first planning period of each scenario.
- Resource Additions (except renewables) will be calculated based on Known and Planned Additions for all scenarios.
- Imports will be assumed to remain constant from the 2024 value through the second planning period.
- Dispatchable DR will be assumed to remain constant from the 2024 value through the second planning period.
- Behind-the-meter PV is extrapolated beyond 2024 using a logarithmic trendline.
- Behind-the-meter CHP and supply-side CHP are both held constant post 2030.
- RPS resource additions listed in the Scenario Tool for years 2025-2034 will be calculated using the RPS Calculator based on the assumption of maintaining the 33% (or 40%) RPS target in 2034. First, the 2014-2024 growth rate in net statewide retail sales for the scenario is used to project net statewide retail sales in 2034. Next, the RPS Calculator is run to produce a projection of additional renewables in 2034 to maintain the RPS target. Finally, this projection in the form of NQC values is plugged into the Scenario Tool by dividing the projection into equal amounts added each year from 2025 to 2034.

4.3.2 Deliverability

Resources can be modeled as Energy-only or Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, assumes that the renewable resource portfolios provided by the CPUC will require deliverability. Beyond that, however, in order to better allow for analysis of options for providing additional generic capacity, any additional resources will only be assumed Deliverable if they meet one of two criteria:

(1) Fits on the existing transmission and distribution system,[58] including minor upgrades,[59] or new transmission approved by both California ISO and CPUC, or

(2) Baseload or flexible resources.[60]

This assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

4.3.3 Price Methodologies

The same methodologies as were used in the 2012 LTPP shall be used for the 2014 LTPP.

Natural Gas

The CEC's Natural Gas Reference Case as put forward in the 2013 IEPR shall be used as the base for calculating natural gas prices.[61] This price series was constructed to be consistent in baseline assumptions with the CED forecast and therefore the two are congruent for planning purposes.

Greenhouse Gas

The Greenhouse Gas (GHG) price forecast as put forward in the 2013 IEPR Natural Gas Market Assessment: Outlook report, to be published in December 2013 by the CEC, shall be used as the base for calculating GHG prices.

Price differentiation may occur, for example, specified imports shall be subtracted from production cost modeling and accounted for, and then remaining imports would be assigned annual GHG values based on an implied market heat rate or other value.

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[58] For this purpose, "fits" refers to the simple transmission assumptions listed on tab g – TxInputs of the 33% RPS Calculator. Staff shall collaborate with the California ISO to update the assumptions and to apply these assumptions to the resource portfolios.

[59] Minor upgrades do not require a new right of way; other factors such as cost are not considered.

[60] Flexibility currently does not have a standard definition, but a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.11-10-023). Generally speaking, baseload resources are those that provide a constant power output, such as a nuclear plant while flexible resources are those that can respond to dispatch instructions. There is some overlap between these two categories, for example a baseload design combined cycle plant could provide some flexibility.

[61] The Energy Commission 2013 IEPR Revised Burner-tip Price Forecast can be obtained as described here: http://www.energy.ca.gov/2013_energypolicy/documents/2013-11-19_Notice_of_Availability.pdf

5 Planning Scenarios

The LTPP scenarios are developed to help answer current resource planning questions before the CPUC. The critical questions facing the 2014 LTPP include the following:

1. What new resources need to be authorized and procured to ensure adequate system reliability, both for local areas and the system generally, during the planning horizon?
    - What is the need for flexible resources and how does that need change with different portfolios? What operational characteristics (e.g. ramp rates, regulation speeds) are needed in what quantities? Are these needs location specific?
    - How does increased penetration of preferred resources affect reliability?
    - How does the potential retirement of major resources (e.g. once-through-cooling, nuclear) change the resource needs?
    - How might GHG emission constraints impact portfolio design?
    - How can reliability needs be balanced against costs, while also creating opportunities for achieving economically efficient outcomes?
2. What mix of resources minimizes cost to customers over the planning horizon?
    - Is there a preferred mix of energy-only, fully deliverable resources, and demand side resources? How does this mix vary depending on the operational characteristics of the resources?
    - Does increased distribution-level generation reduce overall costs?
    - What synergies exist between generation and transmission resources, and between different types of supply resources that can be used to limit overall costs?

The TPP scenarios are developed for the CAISO transmission planning process, to assess the transmission system and propose transmission plans that identify cost-effective transmission additions or non-conventional alternatives over the planning horizon, based upon the following objectives:

1. Maintain reliability of the transmission system, both at the system level and in local planning areas;
2. Integrate the renewable generation in the CPUC RPS portfolios into the transmission system;

3. Perform an economic assessment of potential transmission projects.

5.1 2014 Planning Scenarios

The following scenarios were crafted through a collaborative effort amongst CPUC, CEC and CAISO staff to reflect a reasonable range of possible energy futures. A primary goal is to assess the differences in potential reliability needs for each of these scenarios, especially operational flexibility needs. The different scenarios should not speculate on what specific resources might fill any need, rather, the scenarios will establish what the needs are in each of these possible futures. Afterwards, any scenarios showing need may be restudied with various resource options to determine how to best fill any need. The analysis of each scenario will include emissions and emissions cost information, but there will be no comprehensive analysis to optimize for least cost and lowest emissions in this LTPP cycle.

Inevitably, resource limitations will likely demand prioritization of the scenarios for their use in the LTPP. The scenarios[62] shall be studied in the following order:

1. Trajectory
2. High Load
3. Expanded Preferred Resources
4. 40% RPS in 2024
5. High DG

The CAISO will likely only have the resources to study 3-4 scenarios, plus 1 or 2 sensitivities, within the first year of the LTPP cycle. In the second year of the LTPP cycle, CPUC staff expects to facilitate additional studies with varying additional resource options to determine the best way to fill any need found from studies conducted during the first year of the LTPP cycle. The CAISO may restudy scenarios that had need, exploring the various additional resource options the CPUC proposed. Analyses to determine the best way to fill any need shall first consider existing procurement authorizations that were not studied in the first year of the LTPP cycle (i.e. part of 2012 LTPP Track 1 and all of Track 4). If any need remains, three additional

[62] Additional modeling efforts using the TEPPC 2024 Common Case should be consistent with version 1.5. The CAISO at this time has updated its PLEXOS deterministic database for the Trajectory and 40% RPS in 2024 scenarios to incorporate the TEPPC 2024 Common Case version 1.5. There are no plans to update any of the other scenario databases at this time.

resource options may be studied, depending on the amount and nature of reliability need. The additional resource options are as follows, but are not limited to these three:

1. High DR
2. Large-pumped storage
3. Non-pumped storage

Any LTPP party may choose to conduct its own technical studies to inform the LTPP proceeding by using the Assumptions and Scenarios described in this document, replicating the CAISO's studies, or creating their own scenarios. More weight will be given to analyses that follow the guidelines and general assumptions in this document so that results are directly comparable between studies from different parties and the CAISO.

The remainder of this section qualitatively describes the rationale for each scenario and provides additional details on the assumptions forming that scenario. The Scenario Matrix shown in the following section summarizes the assumptions that form each scenario.

5.2 Trajectory Scenario

The Trajectory scenario is the control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices. This scenario assumes an average level of economic and demographic growth, and as such, uses the Mid load case for the 2013 IEPR CED forecast. This is paired with the Mid AAEE scenario from the 2013 IEPR CED forecast. The Trajectory scenario assumes no incremental demand-side small PV or CHP beyond what is already embedded in the 2013 IEPR CED forecast. For supply-side resources, this scenario assumes the default for conventional additions, no net growth in supply-side CHP, the default for storage and DR, a commercial-interest driven RPS portfolio maintaining the 33% standard in 2024, no nuclear retirement, a low level of renewable and hydro retirement, a mid level of retirement for other resource types, the default for imports, and accounts for existing procurement authorizations.

5.2.1 TPP Application of the Trajectory Scenario

The CAISO will use the Trajectory Scenario in the transmission planning process to assess the transmission system and propose transmission plans that identify cost-effective transmission additions or non-conventional alternatives over the planning horizon. The categories of transmission additions considered by the CAISO in this process are based upon the following objectives:

1. Reliability - Maintain reliability of the transmission system (local planning areas and the bulk system);
2. Policy-driven - Integrate the renewable generation in the CPUC RPS portfolios into the transmission system;
3. Economic - Perform an economic assessment of potential transmission projects.

As illustrated in the Scenario Matrix in the following section, the various components of the TPP use different weather variants of the Mid load case from the 2013 IEPR CED forecast. Also as described above in the Planning Assumptions section of this document, the local reliability studies portion of the TPP diverges from the Trajectory Scenario as follows:

1. Uses the Mid 1-in-10 weather year peak demand forecast.
2. Uses the LowMid AAEE version of the managed demand forecast.
3. Uses the “First Contingency” subset of total DR capacity instead of the entire DR capacity available from all programs.

Both the Policy-driven and Economic Studies portions of the TPP will evaluate impacts from three cases, each maintaining a 33% RPS in 2024:

1. A commercial-interest driven RPS portfolio;
2. A similar commercial-interest driven RPS portfolio that includes new transmission out of the Imperial CREZ;
3. A High DG driven RPS portfolio.

5.2.2 Diablo Canyon Impact Sensitivity

This sensitivity off of the Trajectory scenario explores the potential loss of about 2,240 MW of baseload capacity from PG&E’s Diablo Canyon Power Plant (DCPP), assuming it retires when its license expires in 2024 (Unit 1) and 2025 (Unit 2). The only difference between this scenario and the Trajectory scenario is the retirement of DCPP. DCPP will actually be assumed offline in 2023 to ensure it is retired within the target year of planned technical studies, 2024.

5.3 High Load Scenario

The High Load scenario explores the impact of higher than expected economic and demographic growth and therefore diverges from the Trajectory scenario by using the High load case from the 2013 IEPR CED forecast. This will model both higher peak demand and higher annual energy consumption, but the Mid AAEE scenario is still assumed here. This scenario also uses a commercial-interest driven RPS portfolio built assuming high load and maintaining the 33% standard in 2024.

5.4 High DG Scenario

This scenario explores the implications of promoting high amounts of distributed generation (DG), which may imply more aggressive pursuit of customer-sited distributed generation programs, and a shift in RPS procurement towards favoring wholesale distributed generation projects located near load pockets. This scenario diverges from the Trajectory scenario by assuming a high incremental amount of demand-side small PV and a low incremental amount of demand-side CHP beyond what is embedded in the 2013 IEPR CED forecast, and uses a High DG driven RPS portfolio maintaining the 33% standard in 2024. This scenario's impact on the transmission system is effectively explored as part of the CAISO TPP's Policy and Economic studies.

5.5 40% RPS in 2024 Scenario

The 40% RPS in 2024 scenario, which incorporates the "High DG 40% 2024 Mid AAEE" RPS portfolio, would assess the operational impacts associated with a higher RPS target post-2020. Given that the CA legislature is exploring the establishment of a higher RPS target and trends in RPS procurement indicate a possibility of overshooting 33% by 2020, this scenario would provide policymakers with data to evaluate the system impact of this increased penetration of renewables to the grid. This scenario diverges from the Trajectory scenario by using a High DG driven RPS portfolio that targets achieving a 40% standard in 2024.

5.6 Expanded Preferred Resources Scenario

The Expanded Preferred Resources scenario, which incorporates the "High DG 40% 2024 HighMid AAEE + Higher DSM" RPS portfolio, would assess the impact of broadly pursuing higher levels of preferred resources, a policy direction driven by the California Air Resources Board's

(CARB) 2050 greenhouse gas (GHG) emission reduction goals. CARB, via AB 32, seeks to reduce GHG emissions to 80% below 1990 levels by the year 2050. This scenario also explores higher levels of CHP growth because current state goals, including the AB 32 Scoping Plan, continue to promote CHP growth. This scenario diverges from the Trajectory scenario by assuming the HighMid level of AAEE, which is still consistent with the assumption of a Mid load case 2013 IEPR CED forecast. This scenario also includes a high incremental amount of demand-side small PV beyond what is embedded in the 2013 IEPR CED forecast, a high penetration of new demand and supply-side CHP, and a High DG driven RPS portfolio that targets achieving a 40% standard in 2024.

6 Scenario Matrix

The table below defines each of the assumptions for each of the scenarios.

Table 11: Scenario Matrix

	2014 LTPP Scenarios (2024, 2034 Target Years)				Demand		Demand resources modeled as Supply		Supply											
	#	Name	Notes	Priority	Load	AA-EE	Customer PV	Customer CHP	Existing	Conven. Additions	CHP Additions	Storage Additions	Dispatchable DR	RPS Portfolio	Nuclear Retirement	OTC Retirement	Renewable + Hydro Retirement	Other Retirement	Existing Proc. Auth.	Imports
	1	Trajectory	Conservative expected case for TPP and LTPP studies assuming little change in existing policies.	1	Mid(1in2)	Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 Mid AAEE	None	Default	Low	Mid	Default	Default
TPP specific modeling of Trajectory	a	Base-TPP Local Area Reliability Studies	Local area reliability studies using mid 1-in-10 weather normalized demand forecast.	1	Mid(1in10)	Low-Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts adj for LCR	33% 2024 Mid AAEE	None	Default	Low	Mid	Default	Default
TPP specific modeling of Trajectory	b	Base-TPP Bulk System Reliability Studies	Bulk system reliability studies using mid 1-in-5 weather normalized demand forecast.	1	Mid(1in5)	Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 Mid AAEE	None	Default	Low	Mid	Default	Default
TPP specific modeling of Trajectory	c	Base-TPP Policy Studies	Policy studies using mid 1-in-5 weather demand forecast. Assesses the 33% 2024 Mid AAEE and 33% 2024 Mid AAEE sensitivity and High DG 33% Mid AAEE + DSM RPS Portfolios. Power flow studies (busbar level).	1	Mid(1in5)	Mid	IEPR / IEPR / IEPR+High Inc Sm PV	IEPR / IEPR / IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 Mid AAEE / 33% 2024 Mid AAEE sensitivity / High DG 33% 2024 Mid AAEE + DSM	None	Default	Low	Mid	Default	Default
TPP specific modeling of Trajectory	d	Base-TPP Economic Studies	Economic studies using mid 1-in-2 weather demand forecast. Assesses the 33% 2024 Mid AAEE and 33% 2024 Mid AAEE sensitivity and High DG 33% Mid AAEE + DSM RPS Portfolios. Prod cost sims (nodal) only.	1	Mid(1in2)	Mid	IEPR / IEPR / IEPR+High Inc Sm PV	IEPR / IEPR / IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 Mid AAEE / 33% 2024 Mid AAEE sensitivity / High DG 33% 2024 Mid AAEE + DSM	None	Default	Low	Mid	Default	Default
Trajectory sensitivity	e	Diablo Canyon Impact	Diablo Canyon retires by 2023.	1	Mid(1in2)	Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 Mid AAEE	DCPP 2023	Default	Low	Mid	Default	Default
	2	High Load	High econ/demo case for 1-in-2 weather year (higher peak and annual energy).	2	High(1in2)	Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% 2024 High Load Mid AAEE	None	Default	Low	Mid	Default	Default
	3	Expanded Preferred Resources	Combination of policies to reflect closer achievement of State preferred resource policies.	3	Mid(1in2)	High-Mid	IEPR+High Inc Sm PV	IEPR+High Inc CHP	NQC List	Default	High Inc CHP	Default	1-in-2 weather load impacts	High DG 40% 2024 HighMid AAEE + Higher DSM	None	Default	Low	Mid	Default	Default
	4	40% RPS in 2024	High penetration of large central station renewables.	4	Mid(1in2)	Mid	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	High DG 40% 2024 Mid AAEE	None	Default	Low	Mid	Default	Default
	5	High DG	High penetration of DG near load pockets, generally < 20 MW in size and excluding projects located outside load pockets (e.g. in middle of desert).	5	Mid(1in2)	Mid	IEPR+High Inc Sm PV	IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	High DG 33% 2024 Mid AAEE + DSM	None	Default	Low	Mid	Default	Default

Resource options for filling any need revealed by technical studies of these Scenarios.

	Name	Notes	Priority	Storage Additions	Dispatchable DR	Existing Proc. Auth.
Procurement Authorizations	Any need shall first be met with expected resources from 2012 LTPP Track 1 and Track 4		i	Default	1-in-2 weather load impacts	Default + remainder of Track 1 + Track 4
High DR	This option explores DR capacity reaching 5% of coincident peak load in 2021, 7% in 2024. Higher growth may be explored depending on		ii	Default	capacity at 7% of peak load	
Large-pumped Storage	This option explores large-pumped storage. Amounts will depend on need.		iii	Default + large pumped	1-in-2 weather load impacts	
Non-pumped Storage	This option explores higher operational utility from Storage Mandate resources, plus additional storage depending on need.		iv	Default + more non-pumped	1-in-2 weather load impacts	

Yellow highlights indicate assumptions that differ from the Trajectory scenario.

7 Appendix

7.1 RPS Portfolios Summary

The table below summarizes the renewable net short calculation for each RPS Portfolio.

Table 12: RNS Calculation Summary

	Renewable Net Short Calculation (GWh) By Portfolio								
	Values in this chart are in GWh	Formula	33% 2024 Mid AAEE	33% 2024 LowMid AAEE	33% 2024 High Load Mid AAEE	High DG 33% 2024 Mid AAEE + DSM	High DG 40% 2024 HighMid AAEE + Higher DSM	High DG 40% 2024 Mid AAEE	33% 2024 Mid AAEE (sensitivity)
1	Statewide Retail Sales - Dec 2013 IEPR		300,516	300,516	317,781	300,516	300,516	300,516	300,516
2	Non RPS Deliveries (CDWR, WAPA, MWD)		9,272	9,272	9,272	9,272	9,272	9,272	9,272
3	Retail Sales for RPS	1-2=3	291,244	291,244	308,509	291,244	291,244	291,244	291,244
4	Additional Energy Efficiency		24,410	16,119	24,410	24,410	36,713	24,410	24,410
5	Additional Rooftop PV		-	-	-	5,360	5,360	-	-
6	Additional Combined Heat and Power		-	-	-	6,729	16,016	-	-
7	Adjusted Statewide Retail Sales for RPS	3-4-5-6=7	266,834	275,125	284,099	254,746	233,156	266,834	266,834
8	Total Renewable Energy Needed For RPS	7*33% (or 7*40%)=8	**88,055**	**90,791**	**93,753**	**84,066**	**93,262**	**106,734**	**88,055**
	Existing and Expected Renewable Generation								
9	Total In-State Renewable Generation		**42,909**	**42,909**	**42,909**	**42,909**	**42,909**	**42,909**	**42,909**
10	Total Out-of-State Renewable Generation		**10,639**	**10,639**	**10,639**	**10,639**	**10,639**	**10,639**	**10,639**
11	Procured DG (not handled in Calculator)		**2,204**	**2,204**	**2,204**	**2,204**	**2,204**	**2,204**	**2,204**
12	SB 1122 (250 MW of Biogas)		**1,753**	**1,753**	**1,753**	**1,753**	**1,753**	**1,753**	**1,753**
13	Total Existing/Expected Renewable Generation for CA RPS	9+10+11+12=13	**57,504**	**57,504**	**57,504**	**57,504**	**57,504**	**57,504**	**57,504**
14	Total Net Short to meet 33% (or 40%) RPS in 2024 (GWh)	8-13=14	**30,551**	**33,287**	**36,249**	**26,562**	**35,758**	**49,230**	**30,551**

The table below summarizes the RPS Portfolios by CREZ.

Table 13: RPS Portfolio Summary by CREZ

Breakout By CREZ							
Scenario Name	33% 2024 Mid AAEE	33% 2024 LowMid AAEE	33% 2024 High Load Mid AAEE	High DG 33% 2024 Mid AAEE + DSM	High DG 40% 2024 HighMid AAEE + Higher DSM	High DG 40% 2024 Mid AAEE	33% 2024 Mid AAEE (sensitivity)
Net Short (GWh)	30,551	33,287	36,249	26,562	35,758	49,230	30,551
	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)
Discounted Core	9,109	9,112	9,112	11,440	14,373	14,518	9,063
Generic	3,311	4,414	5,737	0	1,009	6,605	2,223
Total	12,420	13,526	14,849	11,440	15,382	21,124	11,286
CREZ	MW	MW	MW	MW	MW	MW	MW
Alberta	300	300	300	300	300	300	300
Arizona	400	400	400	400	400	400	400
Baja	100	100	100	100	100	100	100
Carrizo South	900	900	900	300	900	900	900
Distributed Solar - PG&E	984	984	984	3,449	3,630	3,630	984
Distributed Solar - SCE	565	565	565	1,988	3,105	3,105	565
Distributed Solar - SDGE	143	143	143	157	362	362	143
Imperial	1,000	1,000	1,000	1,000	1,000	1,000	2,500
Kramer	642	642	642	62	642	642	642
Mountain Pass	658	658	658	165	658	658	658
Nevada C	516	516	516	266	516	516	516
NonCREZ	185	191	457	133	185	457	182
Riverside East	3,800	3,800	3,800	1,400	1,400	3,800	1,400
San Bernardino - Lucerne	87	87	147	42	87	147	42
San Diego South	-	384	384	-	-	384	
Solano	-	200	200	-	-	200	
Tehachapi	1,653	2,148	2,775	1,285	1,618	3,588	1,483
Westlands	484	505	775	389	475	830	469
Central Valley North	-	-	100	-	-	100	
Merced	5	5	5	5	5	5	5
Total	12,420	13,526	14,849	11,440	15,382	21,124	11,286
New Transmission Segments	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1
	Riverside East - 1	Riverside East - 1	Riverside East - 1			Riverside East - 1	Imperial - 1

The table below summarizes the RPS Portfolios by technology type.

Table 14: RPS Portfolio Summary by Technology

Breakout By Technology							
Scenario Name	33% 2024 Mid AAEE	33% 2024 LowMid AAEE	33% 2024 High Load Mid AAEE	High DG 33% 2024 Mid AAEE + DSM	High DG 40% 2024 HighMid AAEE + Higher DSM	High DG 40% 2024 Mid AAEE	33% 2024 Mid AAEE (sensitivity)
Net Short (GWh)	30,551	33,287	36,249	26,562	35,758	49,230	30,551
	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)
Discounted Core	9,109	9,112	9,112	11,440	14,373	14,518	9,063
Generic	3,311	4,414	5,737	0	1,009	6,605	2,223
Total	12,420	13,526	14,849	11,440	15,382	21,124	11,286
CREZ	MW	MW	MW	MW	MW	MW	MW
Biogas	20	23	23	20	20	23	20
Biomass	103	103	103	103	103	103	103
Geothermal	235	235	235	171	235	235	777
Hydro	-	-	-	-	-	-	-
Large Scale Solar PV	7,411	7,911	8,939	3,595	5,173	9,519	5,969
Small Solar PV	2,074	2,099	2,215	5,745	7,451	7,624	2,057
Solar Thermal	1,350	1,350	1,350	827	1,208	1,350	1,208
Wind	1,227	1,806	1,985	979	1,192	2,270	1,153
Total	12,420	13,526	14,849	11,440	15,382	21,124	11,286
New Transmission Segments	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1
	Riverside East - 1	Riverside East - 1	Riverside East - 1			Riverside East - 1	Imperial - 1

The table below shows the changed composition of the "33% 2025 Mid AAEE" RPS portfolio by Competitive Renewable Energy Zones (CREZs) and by technology type pursuant to revised TPP transmittal letter sent from the CEC and CPUC to the CAISO, dated April 29, 2015. See section 4.2.7 for details.

Table 15: Revised "33% 2025 Mid AAEE" RPS Portfolio Summary by CREZ and Technology

Scenario Name	33% 2024 Mid AAEE
Net Short (GWh)	30,551
	Portfolio Totals (MW)
Discounted Core	9,159
Generic	2,827
Total	11,986
CREZ	MW
Alberta	300
Arizona	400
Baja	100
Carrizo South	900
Distributed Solar - PG&E	984
Distributed Solar - SCE	565
Distributed Solar - SDGE	143
Imperial	1,750
Kramer	250
Mountain Pass	658
Nevada C	516
NonCREZ	185
Riverside East	3,017
San Bernardino - Lucerne	87
San Diego South	
Solano	
Tehachapi	1,653
Westlands	475
Central Valley North	
Merced	5
Total	11,986
New Transmission Segments	Riverside East - 1

Scenario Name	33% 2024 Mid AAEE
Net Short (GWh)	30,551
	Portfolio Totals (MW)
Discounted Core	9,159
Generic	2,827
Total	11,986
CREZ	
Biogas	20
Biomass	103
Geothermal	429
Hydro	-
Large Scale Solar PV	6,832
Small Solar PV	2,054
Solar Thermal	1,303
Wind	1,245
Total	11,986
New Transmission Segments	Riverside East - 1

8 Summary and Explanation for ~~Recommended~~ March 4, 2015 ACR Updates

CPUC Energy Division staff have continued to evaluate the reasonableness of the assumptions and validity of the data detailed in the Assigned Commissioner's Ruling which outlined Planning Assumptions & Scenarios for the 2014 LTPP and the CAISO's 2014-15 TPP[63]. This section provides background on the evaluations staff undertook to arrive at recommended updates.

8.1 Demand forecast and AAEE

The 2014 IEPR Update CED forecasts are expected to be available in December 2014. The 2014 IEPR Update will be the most recent CEC forecast available for use in resource planning studies commencing in 2015. As such, the 2015-16 CAISO TPP is expected to use the 2014 IEPR Update CED forecasts (Mid load case) as its source for the "managed demand forecast". The 2014-15 CAISO TPP used the 2013 IEPR CED forecasts since it was the most recent available data set at the start of 2014. Studies in the 2014 LTPP will continue to use the 2013 IEPR CED forecasts for consistency throughout the two year 2014 LTPP cycle.

Regarding the Additional Achievable Energy Efficiency (AAEE) portion of the "managed demand forecast", the 2014 IEPR Update aggregate projections of AAEE are not expected to change from the 2013 IEPR. However, the CEC intends to provide an updated disaggregation of AAEE savings projections down to the transmission level busbar to the CAISO for use in the 2015-16 TPP. The most recent available year of data on substation peak demand share by customer sector will be used to disaggregate the AAEE savings projections. As described earlier in this document, the 2015-16 TPP will continue to use the Low-Mid AAEE projection in local reliability studies.

8.2 Adjustments to RPS Portfolios

Selecting the Portfolios to Study in the CAISO 2015-16 TPP

As mentioned in section 4.2.6 of this document, CPUC staff are in the process of a major overhaul of the RPS Calculator in the RPS proceeding (R.11-05-005), but this "new" RPS Calculator (v6) is not expected to be ready to inform the 2015-16 CAISO TPP. In light of this,

[63] R. 13-12-010 Commissioner Picker Ruling, released 2/27/2014, available online at: http://www.cpuc.ca.gov/NR/rdonlyres/589B90C6-DC13-47E0-89D5-6448BAE8A725/0/AmendedAttachment022714_ACR.pdf

CPUC, CEC, and CAISO staff held extensive conversations regarding the pros and cons of producing a set of RPS portfolios for the 2015-16 TPP using the current ("old") RPS Calculator (v5). The conversations considered CPUC staff constraints, process alignment challenges, as well as the fact that rerunning the current RPS Calculator would not produce RPS portfolios that differed significantly from the portfolios that were produced and submitted to the CAISO for the 2014-15 TPP.

As a result of these conversations, CPUC, CEC, and CAISO staff decided not to re-run the current RPS calculator, but rather, to reuse 2014-15 TPP RPS portfolios in the 2015-16 TPP, with the limited update of the locational information for distributed generation (DG) projects, as described in section 4.2.7 of this document. This limited update was performed on the "33% 2024 Mid AAEE" and the "High DG 33% 2024 Mid AAEE + DSM" portfolios. These two updated RPS portfolios will be studied in the CAISO's 2015-16 TPP and DG deliverability studies.

Local Area Reliability Studies

The "33% 2024 **LowMid** AAEE"[64] was used for local studies in the 2014-15 TPP. However, the CPUC and CAISO staff have determined that both system and local studies should use the "33% 2024 **Mid** AAEE" [65] portfolio in the 2015-16 TPP. While it is prudent to use the "LowMid AAEE managed demand forecast" in local studies in order to represent the greater uncertainty of peak hour AAEE savings at individual transmission-level busbars (substations), this should not imply that local studies must use a different portfolio than what is used in system studies. The "33% 2024 Mid AAEE" RPS portfolio represents the projected steel in the ground needed to meet the 33% RPS requirement in system studies of the Trajectory Scenario, and therefore should also be the portfolio studied in local reliability studies.

Double-count of existing wind resources

An accounting error regarding the amount of existing RPS-eligible generation that was assumed in the renewable net short (RNS) calculation used to build the 2014 LTPP and 2014-15 TPP RPS portfolios was discovered by CPUC and CEC staff. Existing wind resources representing 945 GWh of renewable generation were accidently double-counted in the existing generation calculation. The total existing RPS-eligible generation originally calculated as 42,909 GWh should have been 41,964 GWh. Consequently, the RNS used to create each RPS portfolio

[64] The "33% 2024 LowMid AAEE" portfolio assumes less additional achievable energy efficiency (AAEE) will be realized than the "33% 2024 Mid AAEE" portfolio. As such, the "33% 2024 LowMid AAEE" portfolio has a higher renewable net short (RNS) than the "33% 2024 Mid AAEE" portfolio. An RPS portfolio with a higher RNS requires more renewable resources to satisfy the RPS target.

[65] The "33% 2024 Mid AAEE" portfolio is incorporated into the "Trajectory" scenario.

should have been 945 GWh larger, meaning that each RPS portfolio should have contained additional renewable resources in order to make up the extra 945 GWh RNS.

The RPS portfolios used in the 2014 LTPP proceeding's operational flexibility studies were created before this error was discovered. CPUC staff, in consultation with the staff of the CEC and the CAISO, have chosen to resolve this error by modeling the missing 945 GWh as extra wind projects with similar attributes and locations as the resources that were double-counted, rather than rerun the RPS Calculator to determine what additional projects the RPS Calculator would have chosen to fill the extra 945 GWh RNS. Staff believes that modeling the missing 945 GWh as extra wind projects instead of modeling an alternative group of renewable projects that an RPS Calculator rerun would have chosen will have no material impact on operational flexibility model results[66]. The CAISO modeling results described in CAISO testimony served to parties on August 13, 2014 reflect the error resolution described here.

The RPS portfolios were also used in the CAISO's 2014-15 TPP studies before this error was discovered. CPUC staff in consultation with CEC and CAISO staff determined that not including the handful of marginal projects to make up the extra 945 GWh RNS would have no material impact on transmission planning results. Furthermore, if CPUC staff reran the old RPS Calculator with a RNS that was 945 GWh greater, the additional projects would have come from the Renewable Energy Action Team (REAT) database, which does not seem to have accurate locational information. As such, CPUC staff feel that it is more reasonable to use the RPS portfolios as is, in the CAISO TPP, than to modify them with inaccurate information from the REAT database.

8.3 Updates to the Scenario Tool

Assumed Lake Hodges counts towards the storage procurement target

The Scenario Tool (v4 and later) has been corrected to reflect that the 40 MW Lake Hodges storage project is an existing resource and assumed to count towards SDG&E's share of the transmission-connected storage target from D.13-10-040. See section 4.2.4 for details.

Updated assumptions for existing LCR procurement authorizations

[66] In fact, preliminary runs using the new RPS Calculator (v6) indicate that wind resources tend to score better than solar PV resources due to the decreasing capacity value of solar PV as more of it is placed on the system. As such, correcting the existing wind resources double-count with extra wind projects is qualitatively more reasonable than correcting it with a rerun of the old RPS Calculator (v5) which would have chosen mostly solar PV projects to fill the extra 945 GWh RNS.

The Scenario Tool (v4 and later) assumption for Resource Additions from existing LCR procurement authorizations has been updated to reflect the information in pending applications A.14-11-012 and A.14-11-016 filed by SCE, and A.14-07-009 filed by SDG&E. The proposed procurement in the pending applications includes storage, some of which satisfies the storage target from D.13-10-040. The Scenario Tool (v4 and later) is also adjusted to reflect this and ensure that the proposed storage capacity is not counted twice as part of the storage target and as part of the LCR procurement authorization.

Double-count of renewables that came online in 2013

The Scenario Tool tracks the total projected fleet of supply-side resources by tallying existing resources online as of November 2013, and new resources expected to come online in each future year. The RPS portfolios described in this document were created to include resources projected to come online after July 31, 2013. Therefore, the Scenario Tool tally of existing resources must not include resources that are already counted in the RPS portfolios. The version of Scenario Tool (v2) published in May 2014 included several renewable resources as existing resources and also as part of the RPS portfolios. Therefore, these resources were double-counted in the Scenario Tool. The version of the Scenario Tool (v4 and later) published with this revised document corrects this double-count. None of the technical studies completed in the 2014 LTPP or any of the RPS portfolios are affected by this error, only the load and resources table and Planning Reserve Margin (PRM) calculation within the Scenario Tool are affected. See the Scenario Tool (v4 and later) for further details.

Updated Scenario Matrix

The Scenario Matrix (Table 11 in this document) within the Scenario Tool has also been corrected to reflect two adjustments to the CAISO TPP's expected usage of planning assumptions.

1. Any DR assumptions used in the TPP shall be based on 1-in-2 weather year impacts. This is consistent with the capacity value of DR for Resource Adequacy.

2. Local reliability studies will use the same RPS portfolio as the bulk reliability studies (i.e. the "33% 2024 Mid AAEE" portfolio).

8.4 Retirements

The Assigned Commissioner's Ruling detailing Assumptions & Scenarios for use in the 2014 LTPP and 2014-15 TPP[67] used a 40 year lifespan assumption for conventional generators (not including OTC facilities which are assumed to retire on schedule with State Water Board compliance dates) in the "mid" level. This is the same figure which has been used in the previous LTPPs, and which has been criticized by some parties. In response to the parties' criticisms, staff invited all interested members of the service list for R.13-12-010 to participate in a technical working group focused on revised retirement assumptions. Representatives from IOUs, CAISO, Calpine, NRG, Office of Ratepayer Advocates, The Utility Reform Network, as well as independent consultants participated in calls, with some parties providing informal written feedback.

Staff evaluated a variety of metrics which could be used in place or, or in conjunction with, the existing 40 year lifespan assumption. The intent was to evaluate whether there was a more accurate measure than a uniform 40 year assumption of facility lifespan. While a facility-by-facility approach to evaluating retirement dates may increase accuracy, this approach would be time consuming and yield data that may be difficult to verify.

Stakeholders identified a variety of factors that may increase the expected lifespan of a facility, including: location within a local capacity requirement (LCR) area, having undergone a recent retrofit, the ability to ramp up and down, and a low emissions profile. Some parties agreed that economics was the primary determining factor that went into a decision to retire or continue to operate a facility, and some parties suggested that a combination of the metrics listed above could be used as a proxy for economic value. Generators within an LCR area, for example, generally produce more valuable energy and capacity and could be more difficult to replace due to permitting and other constraints. However, determining whether all LCR areas should be treated equally, how exactly this contributes to lifespan (i.e. does existence within an LCR extend estimated lifespan from 40 to 45 years?), and whether LCRs change over time were all deemed barriers to an effective implementation of a useful proxy for economic value. Units which recently underwent a retrofit can also reasonably be assumed to remain online longer, especially if this retrofit took place near the end of the assumed 40 year lifespan. However, determining exactly how much a retrofit would add to expected lifespan, and whether all retrofits are considered equal in terms of impact would involve facility-by-facility judgments

[67] R. 13-12-010 Commissioner Picker Ruling, released 2/27/2014, available online at: http://www.cpuc.ca.gov/NR/rdonlyres/589B90C6-DC13-47E0-89D5-6448BAE8A725/0/AmendedAttachment022714_ACR.pdf.

which may be neither practical nor equitable. Flexible generators could also be assumed to be more valuable, especially given the current focus on ramp-able resources. However, the need for – and definition of – flexible resources is still being evaluated in the current Resource Adequacy and LTPP proceedings. Staff would be prejudging the outcome of these proceedings by assigning some additional value or lifespan based on a resource's flexibility. Efficient, less GHG-intensive generators are also likely to be more valuable. However, making assumptions about future changes in law and policy that are difficult if not impossible to accurately estimate should be avoided. Modifying retirement assumptions used in our planning will only contribute to increased accuracy if staff can be certain of their validity.

Hours of operation was also considered as a metric to be used in conjunction with, or instead of, facility age: the rationale being that facilities with fewer engine hours could be expected to endure longer due to less wear and tear on moving parts. However, Calpine pointed out that this may be misleading as the most efficient and valuable units may the ones operating most often – and those very valuable units would be the least likely to be retired and more likely to be retrofitted. Finally, some stakeholders suggested a "laddered approach" to retirements wherein a number of MWs are reduced over time. A similar suggestion was to apply a certain percentage to facility retirements, such as assuming that 2.5% of generators retire in a given year. While potentially effective at the system level, this type of approach is not appropriate for the TPP, which requires specific locational information for planning purposes.

After evaluating these options, staff proposes to use an existing contract as a modifier to extend assumed lifespan. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of that contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Energy Division will periodically request confidential procurement data from the utilities to screen for such facilities. Existing contracts will only be used to increase assumed facility lifespans, those with shorter-term contracts will be assumed to obtain new contracts throughout the lifespans.

(End of Attachment)